FINAL REPORT
February 4, 2001

Everett Delta System Impact Study Results

By Gordon Comegys
Bonneville Power Administration
Transmission Business Line

SUMMARY

Florida Power and Light Energy (FPLE) requested Point to Point (PTP) Long Term Firm Transmission service from the Bonneville Power Administration-Transmission (BPAT) via the Open Access Transmission Tariff (OATT) process to deliver power from their proposed new Everett Delta generation. The requested commencement dates are September 2002 for a 250 MW demand and January 2004 for a 500 MW demand, with the Point of Receipt at Snohomish Substation and the Point of Delivery at Vantage 230kV. BPAT determined that a System Impact Study (SIS) was required to address the following objectives: (a) determine if Available Transfer Capability (ATC) will exist without system expansion, and (b) identify the need and approximate scope of a subsequent System Facilities Study (SFS) if insufficient ATC is forecasted for the requested service.

The Puget Sound Area Long Range Study, a separate study, has identified system changes that will be implemented by 2003. The specific alternative to be selected is not known. The preferred alternative from BPA's viewpoint is named the W1 plan. This Everett Delta SIS examines impacts of the proposed generation on two alternatives: the W1 plan and the W4 plan.

The SIS conclusion is that system expansion is required to accommodate the simultaneous transmission uses with Everett Delta. The scope of system expansion is a Remedial Action Scheme (RAS) for the 250 MW generation level. Everett Delta needs to be incorporated into the west side RAS scheme, which drops generation for 500kV outages between Everett, WA and Portland, OR. The 500 MW generation level will require either additional local RAS or a new transmission line. A separate investigation will be needed to address the practical limits of additional RAS compared to addition of a transmission line. One transmission line alternative is a new 11 mile Snohomish to Snoking 230kV line with a sectionalizing breaker addition at Maple Valley.

The transmission expansion prerequisites for Everett Delta 500 MW transmission service will depend on the determination of the prior committed uses. This effort is currently in progress. It will be part of an RTO West FTR filing with FERC scheduled for June 2001.

In the absence of the known firm committed uses, this SIS identifies generation patterns below simultaneous uses, without new transmission lines, that result in compliance with reliability criteria.

The next step in the process is to perform a SFS. The SFS should include the identification of alternatives, selection of a preferred plan of service, construction schedule, and cost estimates. A parallel investigation is needed for the following: resolution of the system design issue for load service versus bulk power transfers, resolution of Total Transfer Capability (TTC) allocation between transmission owners, and updated information on the prior firm committed uses.

TABLE OF CONTENTS

REPORT

1 Background

1.1 Present day Puget Sound transmission reliability management

Operation to ensure that the power flow does not exceed the reliability limits in the Puget Sound area is primarily achieved by managing import and export with Canada on the Ingledow-Custer lines. The Ingledow-Custer lines have a north to south Rated Transfer Capability (RTC) of 2850 MW, which occurs during non-simultaneous conditions. The Operating Transfer Capability (OTC) is frequently below the RTC for conditions that depend on ambient temperature, load level, outages, and area generation. The OTC for all lines in service is described by seasonal nomograms, which quantify the OTC depending on generation at Whitehorn, Fredonia, Tenaska, Enserch, March Point, Sumas, Diablo, Ross, Gorge, and Jackson.

1.2 Long Range Puget Sound Area Transmission Planning

Information is located on BPAT's web site at http://www.transmission.bpa.gov/orgs/opi/system_news/index.shtm, item "Puget Sound Area Long Range Study" posted 27Sep00 with additional information posted 01Nov00. A public meeting was held in Vancouver, British Columbia in November, 2000 with the alternative system expansion plans presented and discussed. This Everett Delta System Impact Study examines the proposed generation addition assuming either the W1 plan or the W4 plan will be implemented.

1.2.1 W1 plan

The preferred system expansion alternative identified at this time is the W1 plan, which is defined as (a) maintain the present two Maple Valley-Snoking-Bothell 230kV lines, (b) add a Schultz-Echo Lake 500kV line that replaces the Schulz-Raver #2 line, (c) add a Snoking 500/230kV transformer and tap the Monroe-Echo Lake 500kV line, (d) reconductor Bothell-Sammamish 230kV line, (e) tap the Bothell-Sammamish 230kV into Snoking, (f) reterminate the Horse Ranch Tap on the Monroe-Snohomish line into Snohomish 230kV bus section 4, (g) reterminate the Bothell terminal of Sedro-Horse Ranch Tap-Bothell to Bothell section 5, and (h) perform miscellaneous line upgrades.

1.2.2 W4 plan

The W4 plan differs from W1 plan in the following areas (a) The 2nd Maple Valley-Snoking-Bothell 230kV line is not included, (b) the existing Maple Valley-Snoking-Bothell 230kV line is not looped into Snoking, (c) the existing Bothell-Sammamish 230kV line is not tapped into Snoking, (d) a new 230kV line needs to be constructed from Snoking Tap to Snoking (13 miles).

1.2.3 Other possible plans

A separate report by the other area transmission owners and PowerEx possibly identifying other alternatives may be issued in February, 2001.

1.3 FPL Transmission Service Requests

FPL requested transmission service beginning in 2003 (requests 204, 205, 206, 207 in the long term firm request queue). The Point of Receipt on BPA's system is Snohomish substation and delivery is Vantage 230kV ("Mid C") for 250 MW or 500 MW total demand.

2 Objectives

2.1 Comply with the Open Access Transmission Tariff

FPL submitted an application for delivery of the power in accordance with the Open Access Transmission Tariff (OATT). BPAT responded by tendering an agreement to perform a System Impact Study because the Available Transfer Capability (ATC) was unknown with the changes created by the proposed generator. Following completion of the SIS, BPAT is required to either tender a transmission service agreement if ATC is determined to be adequate, or to tender an agreement to perform a System Facilities Study if the SIS identifies the need for system expansion.

2.2 Forecast constraints

The present Puget Sound area transmission planning objectives do not include addressing firm point to point delivery of the Everett Delta generation. This SIS addresses whether the future system expansion plans are sufficient to accommodate the Everett Delta generation along with the system uses contemplated in the system design. If other system uses are reduced by the Everett Delta generation, the impact is identified. The need for system expansion is determined by other factors such as committed uses and the assumed future reliability management of the network (see section 4.3).

2.3 Calculate long term firm committed uses

Quantifying the firm Available Transfer Capability requires calculation of the prior firm commitments if the system studies show that simultaneous uses will exceed the Total Transfer Capability within the network.

2.4 Comply with grandfathered commitments

BPAT and PSE each have responsibilities to ensure its actions will maintain a Rated Transfer Capability from Ingledow to Custer at 2850 MW in the month of August for conditions within the Puget Sound area (does not apply to conditions outside of the Puget Sound area). BPAT also has a commitment to deliver the Canadian entitlement, which is a firm commitment to maintain 1270MW from Custer to Ingledow, as well as provide transmission service to serve local load in the Puget Sound area for which transmission service has been purchased.

2.5 Determine existence of Available Transfer Capability (ATC)

If (a) potential simultaneous uses will exceed reliability limits, and (b) the calculation of the firm commitments plus transmission reliability margin (TRM) is less than the reliability limits, then ATC exists and BPAT offers the transmission service to the requestor.

2.6 Identify Need and Potential Scope of System Expansion

If ATC does not exist, then BPAT identifies the approximate scope of system expansion needed to accommodate the request. BPAT is required to tender a System Facilities Study agreement to the requestor. The System Facilities Study identifies the alternatives and performs the preliminary engineering. The requestor agrees to fund the study, or is deemed to withdraw their request. At the conclusion of a System Facilities Study (or the ROD of an EIS), BPAT tenders the transmission service agreement which the requestor either accepts or is deemed to withdraw their request.

3 Methodology

3.1 Screening for conditions exceeding facility thermal limits

Every single and common mode contingency is studied with and without the proposed new generator for simultaneous conditions. If thermal overloads with the assumed model are found, then the non simultaneous regional interchange and generation conditions are calculated that do not result in power flow exceeding reliability limits. For the simultaneous conditions that do exceed reliability limits, a minimum system expansion alternative is estimated, such as remedial action schemes. With the minimal system expansion assumption as a worst case test, the system is screened for low voltage, voltage stability, and transient stability criteria violations.

3.2 Low voltage screening

With the assumed system expansion in place following the thermal screening, the system model is screened for low voltages and voltage stability criteria violations. The data on generator reactive capability and interconnecting facility assumptions become important during this phase. For Everett Delta generation, an assumption of zero reactive capability at the Snohomish 230kV point of receipt is modeled for voltage and voltage stability screening. The generator is assumed to supply the reactive losses of the step up transformer and the line delivering the power to the Snohomish 230kV bus.

3.3 Voltage stability screening

The P-V technique is applied. Generation is incrementally increased and decreased at strategically selected locations to gradually increase power flow across constrained paths, until a voltage stability limit is found. If the limit is above the thermal limits or RTC of a path, no further study is performed. If the voltage stability limit is below the thermal or RTC limits, the need for system expansion (including RAS) is determined. To determine voltage stability limits associated with Everett Delta, the possible new I-5 corridor generation was incrementally added in queue order, with generation displaced at thermal plants in the McNary and Hanford areas. The 2000 summer operating model was used for north to south conditions, and the winter 2000-2001 operating model was used for the south to north conditions. The operating models were used because (a) they provide the worst cases since assumed future Puget Sound lines are not represented, and (b) voltage stability is sensitive to the model outside of the Puget Sound area and the operating case recently received extensive peer review.

3.4 Transient stability screening

Transient stability studies address two objectives: (a) determine the transfer trip requirements on the adjacent lines of the interconnection, and (b) determine wide area effects that may limit transfers below the limits calculated for thermal and voltage stability.

4 Assumptions

4.1 Future system expansion

4.1.1 Either the W1 plan or the W4 plan for the Puget Sound area and Northern Intertie (NI) will be implemented.

Both plans are examined with the Everett Delta generation. To provide a direct comparison with the publicly available NI system studies, the system models that represent the W1 and W4 plans provide the reference point for Everett Delta impact studies. The NI cases named W1S02, W4S02, J06NS172, and J06NS186 are used. These cases represent the two simultaneous conditions that could result in power flow exceeding reliability limits in the model. These two conditions are (a) summer loads and ambient temperature with high Puget Sound area surplus generation and high import from Canada on the Ingledow-Custer 500kV lines, and (b) winter peak loads and ambient temperatures with low Puget Sound area generation and high export to Canada on the Ingledow-Custer 500kV lines.

4.1.2 The Schultz-Hanford 500kV proposed line addition is not assumed in place.

The reliability screening assumes this proposed line on the east side of the grid is not in place. This proposed line has the potential, with series compensation, to decrease the north to south summer power flow by roughly 200 MW between Monroe, Echo Lake, Raver, Paul, Allston, and Keeler which could allow higher levels of existing and new generation. Without this line, the impacts of Everett Delta are quantified by identifying reliability limits on generation and Ingledow to Custer power flow.

4.2 Reliability Criteria

Compliance with the WSCC and NERC system design criteria is assumed. A list of common mode contingencies is contained in Attachment A (MS Word97). These supplement the single branch contingencies.

4.3 Future Reliability management

4.3.1 Past practice

Past planning practice primarily designed the system to accommodate simultaneous uses within the Pacific Northwest network. The reliable flow on the transmission in the I-5 corridor was kept within limits by managing the Ingledow-Custer flow with Canada. For predicted conditions where the flow management with Canada did not achieve reliable flow, the past practice has been to plan operating actions in real time with generation shifts and mid hour control area interchange schedule changes, often with affected utilities under the auspices of the NWPP.

4.3.2 Assumed Future Practice

The assumed reliability management for the future departs from the past practice in the following manner: system expansion will not be planned to accommodate more than the contracted commitments and transmission reliability margin. Predicted power flow across internal network constraints will be managed within reliability limits (calculated in accordance with NERC/WSCC criteria) prior to actual operation. Paths within the network will therefore be defined with the objective to allow only transactions that result in power flow within the reliability limit consistent with the transmission rights. The transfer capability of forecasted constrained network paths will need to be calculated and information from the transmission users to the transmission operator will need to be sufficient to guarantee the forecasted flow will not exceed the reliability limit. Actual flow will only exceed the reliability limit in the event of an unplanned outage, and operating action will be planned and implemented to reduce the flow to levels in accordance with operating criteria. This assumption essentially means that not all generators will be scheduled to generate if the system is not able to reliably provide for simultaneous uses.

4.4 Firm Total Transfer Capability

Long term Total Transfer Capability (TTC) is assumed to be the maximum reliable flow levels demonstrated in the system studies for the condition with all lines in service. For paths with TTC sensitive to other conditions such as ambient temperature or other path flows, the long term TTC is described via nomograms and the long term firm TTC is the lowest credible value.

4.5 Points of Delivery that are not actual sinks

Transmission service requests may have POD's where the power can't be consumed, either because of insufficient load or the load already has more transmission service rights than it can simultaneously use. The intent is to specify a POD where a second transmission service contract will take the power from the POD to another POD that is the actual sink. The second transmission service contract may exist with a Transmission Contract Holder (TCH) who will not exercise rights for other generation, or it may not exist and it will be requested in the future with a process that could involve a system impact study. The Everett Delta study assumes a second transmission service request will not cross a path that will need a system impact study. If it does, then the system impact study will be performed at that time in accordance with the OATT. One example of the impact of this assumption on the Everett Delta study is that the North of John Day (NJD) path will not be loaded above it's capability, because the requested Vantage POD is north of the constraint. To ensure the path doesn't exceed its limit, the Everett Delta generation may displace thermal generation north of the NJD in the system model if needed to maintain NJD within reliable power flow limits.

4.6 Generator Interconnection Model

The thermal limit and voltage stability contingency analysis assumes the Everett Delta generator is radial into the Snohomish 230kV bus with no step up transformer represented and zero reactive capability. The model for transient stability studies was modified to include the step up transformer, transient reactive response, inertia, and impedances as provided by FPL. Contingency analysis was not performed on the Snohomish system (SPD has contracted with PTI to perform planning).

4.7 Transmission Line Capacity Ratings

If line capacity ratings in the system model are exceeded in a study, the time to sag violation is assumed too short to depend on mitigating action by operator intervention. This assumption is for long term firm planning purposes. It is assumed to add some margin for unknowns during actual operation. Forty nine branch data ratings and one topology representation (Bothell-Sammamish loop in at Snoking for W1 plan) that were changed from the NI cases specified in section 4.1.1 are listed in Attachment A (MS

Word97). These changes are consistent with the NI W1 and W4 plan assumptions.

4.8 Generator Dropping Requirements

At present, Remedial Action Schemes (RAS) provide the north to south summer transfer capability in the I-5 corridor by dropping generation at Chief Jo, Grand Coulee, Whitehorn, Fredonia, GM Schrum, Mica, and/or Revelstoke. Contingencies that involve RAS include the Custer-Ingledow #1&#2, Custer-Monroe #1&#2, Monroe-Echo Lake, Raver-Paul, Paul-Allston #1 and #2, and Allston-Keeler. The Everett Delta generation is assumed to be part of the west side RAS for the outages south of Monroe, wherever generator dropping is applied for Canadian import. A maximum allowable generator dropping level of 2850 MW is assumed, based on previous studies showing risk of underfrequency loadshedding and with margin for imprecise unit selection for dropping. System expansion beyond RAS for generator tripping is required to accommodate conditions if 2850 MW of generator dropping is insufficient.

RESULTS

5 Thermal facility limit contingency screening

The strategy for assessing facility thermal limits with the W1 and W4 plans is described as follows. The 500 MW generator option is modeled assuming a radial connection to the Snohomish 230kV bus. The contingency analysis, including common mode, is performed for the simultaneous Puget Sound area north to south summer conditions (i.e. maximum Ingledow to Custer flow and maximum credible PSE, SCL, and SPUD generation) and simultaneous south to north winter conditions (i.e. Credible high Custer to Ingledow flow and lowest credible PSE, SCL, and SPUD generation). The contingency analysis is also performed without Everett Delta generation to flag violations of reliability criteria unrelated to the new generation. Power transfer distribution factors (assumes linear incremental flow for a specific network topology, regardless of the system loading) is calculated for every generator in the model. Using these factors, the following generator MW levels are calculated that would eliminate the thermal limit violations: Everett Delta generation level, Canadian generation level with subsequent calculation to relate it to Ingledow-Custer flow, SCL Skagit generation, PSE area generation, and Chief Jo/Coulee generation. Subsequent powerflow studies are performed to validate the linear incremental flow assumption. The possible option of remedial action scheme additions (beyond adding Everett Delta to the existing scheme described in section 4.8) to mitigate overloads is assessed.

5.1 Summer conditions

5.1.1 Overloads in the Puget Sound Long Range Plan models (without Everett Delta)

The analysis shows overloads for the assumed W1 model. These overloads are explained as follows: (a) the common right of way outage with Monroe-Snoking-Echo Lake 500kV and Monroe-Sammamish 230kV line will be submitted to WSCC for exemption due to the calculated mean time to failure of greater than 30 years, and (b) the Paul breaker failure causing loss of the Raver-Paul 500kV and Centralia unit #2 is assumed outside of the Puget Sound Area Long Range Plan study scope, which was defined as conditions north of Paul (line swap at Paul could mitigate the overload of the Tacoma A-CentrSS 230kV).

5.1.2 W1 Northern Intertie/Puget Sound Area plan

5.1.2.1 Puget Sound area 500kV line contingency analysis for thermal limit violations

The 500kV lines in the Puget Sound area are examined separately due to the existing Remedial Action Schemes that initiate automatic generator tripping at generators in BC, in the Puget Sound area at PSE's Whitehorn and Fredonia, the federal Grand Coulee and Chief Joseph projects, and the future Frederickson generation at South Tacoma.

5.1.2.1.1 Overloads with Everett Delta generation

Including Everett Delta in the westside RAS effectively mitigates the incremental loading over the condition without Everett Delta generation for the 500kV single and common mode contingencies north of Raver. Attachment B (Excel97 workbook)demonstrates the need for including the Everett Delta by showing loading with and without the generator dropping. The Raver-Paul contingency has different issues and is therefore described in the separate section below.

5.1.2.1.2 The Raver-Paul contingency

The Raver-Paul outage includes the tripping of the future 250 MW Frederickson generator interconnected at South Tacoma. If the Everett Delta 500 MW amount is also included in the study for generator tripping, the total generator tripping amount exceeds the 2800 MW maximum by 120 MW. Therefore, the Raver-Paul contingency is tested to determine if the Chief Jo and Coulee generator tripping can be reduced, because the location of Everett Delta has the potential of equivalent or increased effectiveness in mitigating the overload. However, replacing Chief Jo generator dropping with Everett Delta will reduce the maximum allowable Chief Jo and Coulee generation by 400 MW (calculated from power flow distribution factors, valid for linear incremental loading). The measure of generator dropping effectiveness is the limiting line section, the South Tacoma to Centralia tap on the South Tacoma-Chehalis 230kV line. The effectiveness of all generators systemwide to reduce the overload was examined. The results show that Everett Delta is slightly more effective in reducing the loading on this line by 1% (i.e. for every 100 MW dropped, the South Tacoma-Chehalis loading is reduced one more MW if dropped at Everett Delta rather than at Chief Jo). The original maximum reliable generation total of Chief Jo and Coulee in the model was 7140 MW. This level is reduced to 6700 MW.

5.1.2.1.3 500kV contingencies at Paul, Paul to Allston, and Allston to Keeler

Forecasted conditions at Paul and to the south of Paul down to Keeler will not support one of the following: (a) Ingledow to Custer flow above 2380 MW, or (b) the generation level above 6500MW at Chief Jo and Coulee. The reason for this is the addition of the 600MW Chehalis Generation Project to be interconnected on the Paul-Allston 500kV #1 line. Chehalis will be dropped for the double line outage from the interconnect point to Allston, and dropped for the Allston-Keeler outage. These conditions exist prior to Everett Delta. If Everett Delta 500 MW is added for this generator dropping, then the allowable conditions are: (a) Ingledow to Custer is less than 2000 MW, or (b) Chief Jo and Coulee is less than 6200MW. The 2850 MW maximum allowable generator dropping magnitude causes the allowable conditions to be restricted below the simultaneous levels.

5.1.2.2 Contingency analysis below 500kV for thermal limit violations

The contingency screening was performed for simultaneous conditions of 2850 MW Ingledow to Custer flow and high PSE/SCL/SPD area generation to identify any thermal limit violations. Thermal limit violations were found. In descending order of percentage severity of the overload (excluding Snohomish bus section outages), six outages causing overloads are listed and examined as follows (powerflow case #):

c2: Bothell 230kV section 1 outage overloads Bothell-Snohomish 230#2 (w1ns2850bc2),
c3: Bothell-Snohomish 230kV #2 outage overloads Bothell-Snohomish 230kV#1 (w1ns2850bc3),
c5: RedmondP-Sammamsh 115 outage overloads Cotagebr-Duval 115 (w1ns2850bc5)
c4: Double Canal-Bothell and Canal-Viewland 115kV outage overloads Broad St-University 115 (w1ns2850bc4)
c1: Bothell 230kV section 5 outage (Bothell breaker opens on Bothell-Horse Ranch-Sedro 230kV) overloads Bothell-Snohomish 230#1 (w1ns2850bc1)
c6: Maple Valley 230kV bus section 2 outage overloads Maple Valley-Snoking 230kV#1 (w1ns2850bc6)

5.1.2.3 Generation levels within transmission thermal limits

Flow through the limiting facility for the contingencies showing thermal limit violations was calculated for every generator in the system model with incremental flow to a point outside of the area. With these factors, example generation patterns that will result within the facility ratings are calculated and summarized below. The factors for all generators are listed in Attachment C (Excel97 workbook).

5.1.2.3.1 Analysis

5.1.2.3.1.1 Summary list of non simultaneous conditions within thermal line limits

Contingency	Ingledow>Custer	Everett Delta	SCL Skagit	PSE CT's	CJ+Coulee
c1	2430	500	650	1150	7140
c1	2850	400	650	1150	7140
c1	2850	500	650	916	7140
c1	2850	500	650	1150	5500
c2	1430	500	650	1150	7140
c2	2850	250	650	1150	7140
c2	2850	500	650	271	7140
c2	2850	500	650	1150	3500
c3	1850	500	650	1150	7140
c3	2850	320	650	1150	7140
c3	2850	500	650	664	7140
c3	2850	500	650	1150	4500
c4	2200	500	650	1150	7140
c4	2850	130	650	1150	7140
c4	2850	500	300	1150	7140
c4	2850	500	650	584	7140
c4	2850	500	650	1150	4500
c4	2640	250	650	1150	7140
c5	2230	500	650	1150	7140
c5	2850	130	650	1150	7140
c5	2850	500	200	1150	7140
c5	2850	500	650	664	7140
c5	2850	500	650	1150	4000
c6	2460	500	650	1150	7140
c6	2850	250	650	1150	7140
c6	2850	500	400	1150	7140
c6	2850	500	650	816	7140
c6	2850	500	650	1150	5500

(powerflow cases for c6 contingency: w1ns2850bc6a, w1ns2850bc6b, w1ns2850bc6c, w1ns2850bc6d, w1ns2850bc6e)

5.1.2.3.1.2 Summary for Everett Delta 250 MW generation level

The 250 MW generation level results in no thermal limit violations for the simultaneous conditions, except for the double SCL Bothell-Canal and Canal-Viewland 115kV outage overloading the Broad Street- University 115kV line and the PSE RedmondP-Sammamish 115kV line section outage overloading the Cotagebr-Duval 115kV line section. Both of these overloads exhibit low sensitivity to the Everett Delta generation and high sensitivity to load levels. This appears to be a load service planning issue (see section 9.3).

5.1.2.3.1.3 Summary for Everett Delta 500 MW generation level

The 500 MW generation level results in thermal limit violations for four contingencies. These are (a) Snohomish-Bothell 230kV #1 or Bothell 230kV bus section 1 outage overloading the Snohomish-Bothell 230kV #2 line, (b) Snohomish-Bothell 230kV #2 overloading Snohomish-Bothell 230kV #1, (c) the Bothell breaker opening on the Bothell-Horse Ranch-Sedro 230kV line overloading the Snohomish-Bothell 230kV #2, and (d) the Maple Valley 230kV bus section 2 outage overloading the Maple Valley-Snoking 230kV #2 line. These do not occur for non simultaneous conditions described in section 5.1.2.3.1.1

5.1.2.3.2 System Expansion alternatives to accommodate simultaneous conditions

5.1.2.3.2.1 Potential Remedial Action Scheme

5.1.2.3.2.1.1 250 MW Everett Delta

Assuming the load service issues are addressed as described in section 9.3, the 250 MW Everett Delta transmission request appears to need no additional system expansion for the W1 plan other than including it in the existing westside RAS for contingencies on the 500kV I-5 corridor.

5.1.2.3.2.1.2 500 MW Everett Delta

The most severe overloads result on either one of the Bothell-Snohomish 230kV lines following contingencies that include the other Bothell-Snohomish 230kV line. If RAS and associated line loss logic to drop the Everett Delta generator for an outage of either Bothell-Snohomish 230kV line, then two of the remaining four limiting contingencies involve facilities that are in areas of load service most sensitive to load levels and relatively insensitive to generation levels (see section 9.3). The remaining contingencies are (a) the Bothell breaker opening on the Bothell-Horse Ranch-Sedro 230kV line (contingency c1), and (b) the Maple Valley 230kV bus section 2 outage (contingency c6). Either RAS could be added for the contingencies, or a Maple Valley sectionalizing breaker could be added and add RAS for the Bothell breaker open condition, or the system could be managed to non simultaneous conditions within the thermal limits. The allowable non simultaneous conditions include any one of the following (a) Ingledow to Custer flow is less than 2430 MW, or (b) PSE generation is less than 816 MW, or (c) Chief Jo and Coulee combined generation is less than 5500 MW.

5.1.2.3.3 New Line

A new Snohomish-Snoking 230kV line may be a system expansion alternative to accommodate the simultaneous conditions. To mitigate overloads that result from the Snohomish bus section outages, an alternative could be to have 230kV integrating line bypass Snohomish substation and tie radially into Snoking substation. The contingency analysis for summer shows the overloads are mitigated for the W1 plan, except for the Maple Valley 230kV bus section 2 outage. The bus section outage is mitigated by either of the following two alternatives: (a) reterminate the Sammamish line into bus section#1 (w1ns28mvibc54, w1ns28mvibc55), or (b) add a 230kV sectionalizing breaker between the Maple Valley 500/230kV transformer terminal and the Massachusetts terminal (w1ns28rib50,51,52,53). See Attachment B (Excel97 workbook). A preliminary cost for this system expansion (new Snohomish-Snoking 230kV line, Snoking 230kV terminal, and Maple Valley 230kV sectionalizing breaker) is $15 million. This estimate excludes the additional communications and control infrastructure for including the generator into the BPA control area and the existing westside RAS scheme.

5.1.3 W4 Northern Intertie/Puget Sound Area plan

5.1.3.1 Puget Sound area 500kV line contingency analysis for thermal limit violations

All 500kV contingency issues are identical to the W1 plan described in section 5.1.2.1. Attachment B (Excel97 workbook) shows the need to include Everett Delta in the westside RAS.

5.1.3.1 Contingency analysis below 500kV for thermal limit violations

The contingency screening was performed for simultaneous conditions with 2850 MW Ingledow to Custer flow and high PSE/SCL/SPD area generation to identify any thermal limit violations. Thermal limit violations for the W4 plan were found prior to the addition of Everett Delta generation (identified below). Thermal limit violations were found with the Everett Delta generation. In descending order of percentage severity of the overload (excluding Snohomish bus section outages), six outages causing overloads are listed and examined as follows:

c2: Bothell 230kV section 1 outage overloads Bothell-Snohomish 230#1 (w4ns2850bc2). Note: the line is loaded at 100% of capacity in the model prior to the addition of Everett Delta generation.
c3: Bothell-Snohomish 230kV #1 outage overloads Bothell-Snohomish 230kV#1 (w4ns2850bc3),
c5: RedmondP-Sammamsh 115 outage overloads Cotagebr-Duval 115 (w4ns2850bc5). Note: the line is overloaded at 102% in the model prior to the addition of Everett Delta generation.
c4: Double Canal-Bothell and Canal-Viewland 115kV outage overloads Broad St-University 115 (w4ns2850bc4)
c1: Bothell 230kV section 5 outage overloads Bothell-Snohomish 230#1 (w4ns2850bc1)
c6: Maple Valley 230kV bus section 2 overloads Broad St-University 115kV (w4ns2850bc6)

5.1.3.2 Summary of non simultaneous conditions within thermal line limits

Contingency	Ingledow>Custer	Everett Delta	SCL Skagit	PSE CT's	CJ+Coulee
c1	1900	500	650	1150	7140
c1	2850	170	650	1150	7140
c1	2850	500	650	467	7140
c1	2850	500	650	1150	3500
c2	700	500	650	1150	7140
c2	2850	0	650	1150	7140
c2	2850	500	650	0	5500
c2	1800	250	650	1150	7140
c2	2850	250	650	1150	5000
c3	1330	500	650	1150	7140
c3	2850	116	650	1150	7140
c3	2850	500	650	0	6500
c3	2850	250	650	1150	6000
c4	1700	500	650	1150	7140
c4	2850	0	650	1150	7140
c4	2850	500	170	1150	7140
c4	2850	500	650	200	7140
c4	2850	500	650	1150	4000
c4	2850	250	650	1150	5000
c5	1720	500	650	1150	7140
c5	2850	0	650	1150	7140
c5	2850	500	0	1150	7140
c5	2850	500	650	70	7140
c5	2850	500	650	1150	4000
c6	2130	500	650	1150	7140
c6	2850	140	650	1150	7140
c6	2850	500	320	1150	7140
c6	2850	500	650	449	7140
c6	2850	500	650	1150	5000

5.1.3.3 Analysis

The contingency analysis for the W4 plan prior to adding Everett Delta generation has some lines at or slightly above the thermal limits in the model, indicating potentially no margin for additional generation, depending on its location. For Everett Delta, the generation is not located in an area that would decrease the pre Everett Delta line loadings that are at capacity. Therefore, the Everett Delta addition causes overloads at any level above zero with the assumed conditions. Non simultaneous conditions can accommodate the generation, listed in section 5.1.3.2. If (a) the contingencies and limiting facilities associated with load service are addressed as a separate issue (see section 9.3), and (b) RAS to drop the generator for contingencies involving the Snohomish-Bothell 230kV #1 or #2 line is an alternative (see section 5.1.2.3.2), then the limiting contingency is the Bothell 230kV section 5 outage causing the Bothell breaker on the Bothell-Horse Ranch-Sedro line to open (contingency c1). With the RAS on the

Snohomish lines, the system is within thermal line limits with the Bothell section 5 outage for any of these example non simultaneous conditions: (a) the Ingledow to Custer flow is less than 1900 MW, or (b) Everett Delta is less than 170 MW, or (c) PSE generation is less than 467 MW, or (d) the Chief Jo and Coulee generation is less than 3500 MW. Section 5.1.2.3.3 describes a new line alternative to accommodate simultaneous uses.

5.2 Winter simultaneous conditions

5.2.1 W1 Northern Intertie/Puget Sound Area Plan

The contingency screening revealed several overloads with the assumed system model, but no additional overloads were caused by the Everett Delta generation for the W1 plan (Attachment B, Excel97 workbook).

5.2.1.1 Generation patterns within transmission thermal limits

The NI studies with the W1 plan and low PSE/SCL/SPD generation demonstrated a maximum capability from Custer to Ingledow of 1270 MW without Everett Delta. The Everett Delta generation at 500 MW increases the capability from Custer to Ingledow to 1820 MW (Attachment B).

5.2.2 W4 Northern Intertie/Puget Sound Area Plan

The contingency screening revealed several overloads with the assumed system model, but no additional overloads were caused by the Everett Delta generation for the W4 plan (Attachment B).

5.2.2.1 Generation patterns within transmission thermal limits

The NI W4 studies with low PSE/SCL/SPD generation showed the Custer to Ingledow flow is limited to 870 MW without Everett Delta (determined by extrapolation). The limiting contingency is the Echo Lake-Snoking-Monroe 500kV line overloading the Bothell-Maple Valley 230kV line. Everett Delta generation decreases the number of limiting contingencies and severity of overloads in the system model (Attachment B). The Custer to Ingledow flow capability is increased to 907 MW with 500 MW Everett Delta generation. Without Everett Delta, this model shows a Custer to Ingledow capability of 217 MW, which is a different result from the 870 MW of the original NI study (likely due to extrapolation imprecision).

6 Voltage Stability Screening

6.1 Study method

6.1.1 Summer conditions

The system with summer conditions and Ingledow to Custer flow at 2850 MW was incrementally stressed by adding Everett Delta generation and displacing HPP. If no voltage stability limit was found, the system was continued to be incrementally stressed with other proposed I-5 corridor generation projects at Satsop and Longview displacing thermal generation at WNP2, Hermiston Power Partners, Coyote Springs, and the Hermiston Generating Project. If no voltage stability limit was found with all I-5 corridor generation in the request queue modeled, and up to 2850 MW of generator dropping, then the generator dropping amount was reduced until a limit was found. The purpose of the voltage stability screening is to determine if these limits are lower than the thermal facility limits. If it is lower, then the difference between the thermal and voltage stability limits are quantified in terms of MW to provide information on the margin.

6.1.2 Winter conditions

The system was incrementally stressed with constant winter peak loads by increasing COI and PDCI import and displacing Canadian generation to increase the Custer to Ingledow flow. The maximum Custer to Ingledow flow provides the measurement of the voltage stability limit.

6.2 Study results

6.2.1 Summer north to south flow

The voltage stability limits are higher than the thermal facility limits for both the W1 and W4 plans with summer north to south conditions. No limits were found when all proposed I-5 corridor generation was added, assuming all of the new units were included in the west side RAS, up to the maximum 2850 MW of generator dropping. The generator dropping was incrementally decreased for the contingencies to determine if there is a limit in the model. A limit was found. Loss of the Keeler-Pearl 500kV and the Allston-Keeler 500kV lines due to a Keeler breaker failure results in voltage instability if the total generator dropping is less than 1100 MW. The critical bus is in the vicinity of Ostrander. Assuming that the maximum allowable generator dropping is 2850 MW, the system appears to have at least 1700 MW of voltage stability margin in the model with Everett Delta, Satsop, and Longview generation added. See Attachment E.

6.2.2 Winter south to north flow

The existing voltage stability limit as measured by the maximum allowable Custer to Ingledow flow in the model is 1713 MW, limited by the Chief Jo-Monroe 500kV line outage. The critical bus is in the vicinity of the Raver 500kV bus. Adding 500 MW Everett Delta generation improves the limit to 2131 MW. See Attachment E.

7 Transient Stability Screening

7.1 Local transient stability

Zone two clearing times did not result in instability for lines outside of Snohomish Substation. See Attachment D (MS Word97).

7.2 Regional and interregional transient stability

The inclusion of Everett Delta into the westside RAS was studied. The results show a small increase in the risk of a BC-Alberta separation following the loss of the Monroe-Snoking-Maple Valley 500kV line and associated generator tripping. Inclusion of Everett Delta into the west side RAS should also consider fast generator ramping as an alternative to generator tripping to mitigate this impact. See Attachment D (MS Word97).

8 Estimated firm committed uses prior to Everett Delta request

Since the simultaneous uses exceed the reliability limit during summer conditions with Everett Delta, the level of firm committed uses was investigated. This investigation is not final. More information may become available as a result of FTR work associated with RTO West, perhaps in June 2001. The final calculation of firm committed uses could either delay the commencement date for the requested service until system expansion is completed, or provide the basis for offering transmission service without delay.

8.1 North to South summer conditions

8.1.1 Westside Northern Intertie

At the time Everett Delta entered the queue, the long term firm north to south commitments from Ingledow to Custer totaled 1200 MW. PSE has an allocation of 15% of the NI Operating Transfer Capability (OTC). Therefore, to obtain the 1200 MW level for BPA's allocation, the NI long term firm Total Transfer Capability (TTC) needs to be 1600 MW. Section 2.4 describes BPA's responsibility to maintain a 2850 MW Rated Transfer Capability for conditions within the Puget Sound area in the month of August.

8.1.2 PSE Area Generation

PSE has 400 MW of grandfathered BPA transmission capability rights for their surplus control area generation to export to California on their COI ownership share. The power flow model does not attempt to precisely represent this condition, but the simultaneous PSE generation is assumed to cover this condition in summer.

8.1.3 SCL Skagit Generation

SCL has rights to 160 MW of point to point open access transmission capability for their surplus generation to export to California on their ownership share of the COI. The power flow model does not attempt to precisely represent this condition, but the simultaneous SCL generation is assumed to cover this condition in summer.

8.1.4 Chief Joseph and Grand Coulee Generation

BPA's Power Business Line (BPAP) has long term firm transmission reserved for all federal load customers from the federal projects. BPAP has not reserved long term firm transmission for their surplus generation. Historical data for the past five years shows the combined Chief Jo and Grand Coulee generation does not exceed 4700 MW in summer when the federal system generation is equal to or less than the federal system load. In addition to the generation to serve load, the Chief Jo and Coulee projects historically have provided 80% of the BPA control area reserves. The NWPP has determined (November 2000) that transmission will not be reserved for the NWPP reserves in advance of a contingency. These investigation results are preliminary. More information should become available as FTR allocations are determined for the RTO West.

8.2 South to North winter conditions

Simultaneous conditions are improved with Everett Delta. Long term firm commitments did not need investigation.

9 Issues that need to be addressed

9.1 RAS as an alternative

The minimum system expansion needed to accommodate Everett Deltas transmission request is generator tripping or fast automatic ramping as part of a Remedial Action Scheme that will increase transfer capability. The facilities study should address the following generator dropping issues described in this section 9.1.

9.1.1 Increase Control Area Reserves

Reserves for the control area must be the higher of the most severe single contingency, or 5% of hydro and 7% of thermal. At the present time, transfer capability is partly achieved by dropping up to 1820MW in BC-Hydro's control area. Shifting the generator dropping to BPA's control area will increase the generation dropping in BPA's control area. BPA will need more reserves than in the past.

9.1.2 Maintenance activity may impact transmission users

Planned maintenance is now scheduled to minimize disruption to transmission users. RAS, as used as an alternative to significant system expansion, will decrease the windows of opportunity that, in the past, minimized or avoided adverse impacts on transmission users.

9.1.3 Probability of increased curtailments

Existing transmission users could be subject to more curtailments if RAS is used in place of system expansion, due to (a) the higher load factor on the lines throughout the year and (b) the reduction in margin which could cause curtailments from small differences in actual conditions from the assumed conditions. Once new firm service is committed, the present rules require pro-rata curtailment of all existing firm and new firm service.

9.1.4 Increased management of complex control and communications systems

The need for more management and trained staff than presently exists may occur if the transmission availability and transmission commitments become more dependent on complex control and communication systems.

9.1.5 Implementation problems for precise generator tripping quantities

The Raver-Paul outage in the model required shifting 70 MW of generator dropping from Chief Joseph to Everett Delta. However, the precision in arming units to be dropped can't meet this precision. It is possible that the actual conditions at Chief Jo will cause the amount armed to be the same as without Everett Delta, and the resulting drop will be higher than planned.

9.2 Absence of I-5 corridor TTC commercial allocation

The WSCC method for managing inadvertent flow when simultaneous uses exceed transmission capability is to define cutplanes that provide a basis for calculating maximum reliable flow and provide a means for the multiple owners to ensure the predicted flow is within the calculated reliability limit. The WSCC cutplane method has two components: (a) calculate the transfer capability and (b) negotiate an allocation for each owner. The I-5 corridor has no defined cutplane for transmission allocation purposes. If each owner assumes transmission rights equal to the thermal capacity of their lines and manages transactions up to those capacities, the flow could exceed the reliability limit because the sum of the thermal line capacities always exceeds the calculation of the total transfer capability from system studies.

9.3 Load service versus bulk power transfers

9.3.1 PSE system

An example of a line designed for area load service that is impacted by parallel flow from the bulk transmission system is the Cotagebr-Duval 115kV during a RedmondP-Sammamsh 115kV outage. The thermal capacity is 64 MW. The Everett Delta generator with 500 MW assuming the W1 plan causes 6.8 MW additional MW to flow on this line, causing an overload that did not previously exist. The 1.4% flow sensitivity to the generator is so low that the generator does not mitigate the overload without a large reduction of 370 MW.

9.3.2 SCL system

The Everett Delta generator flow on the Broad St - University 115kV during the double Bothell-Canal and Canal-Viewland 115kV outage is about 5% of the generation level. The generator needs to be reduced by 370 MW to mitigate the 20 MW overload in the model.

9.3.3 Summary of the Issue

Bulk power transfers have low flow sensitivity through the lines serving area load. If no capacity margin is planned for this area load service with lines in parallel with the bulk transmission system, the bulk power transfers can be severely restricted resulting in inefficient transmission use. The area load serving utilities are presently addressing these issues.

9.3.4 Mitigation alternatives

9.3.4.1 Design load service facilities with capacity margin

If the area load service transmission lines stay in parallel, then designing the system for capacity margin can accommodate the parallel flow.

9.3.4.2 Speed up area load service projects

Speed up area service planning projects for projected load growth may provide for the margin for parallel flow.

9.3.4.3 Change Area Load Service Planning

Two possible changes are (a) sectionalizing the area load service lines to eliminate the parallel flow or (b) redesign loop service to originate from a single source from the main grid to eliminate parallel flow.

9.4 Scope of System Expansion

The results of this system impact study demonstrate the need for system expansion. The system expansion can be limited to RAS to drop Everett Delta for outages the 500kV contingencies, the Snohomish bus sections, the Bothell-Snohomish 230kV #1, the Bothell-Snohomish 230kV #2, and (for the W1 plan) the Maple Valley 230kV bus section 2. This assumes the parallel flow on area load service lines is mitigated by some means such as suggested in section 9.3. If RAS is determined as unacceptable for the short term as a result of issues raised in section 9.1, then the scope of system expansion will need to include new lines. Example alternatives of a new line that could be addressed in the system facilities study is a 230kV line from Snohomish to Bothell or Snohomish to Snoking with an optional loop-in at Bothell. The Snohomish to Snoking 230kV alternative was examined in section 5.1.2.3.3 for the W1 plan. This alternative appears sufficient to eliminate the overloads, except load service overloads and Snohomish bus section outages, and does not create new overloads for the simultaneous conditions.

9.5 Sensitivity to future system expansion assumptions

The assumed Kangley-Echo Lake 500kV line addition (shown as the Schultz-Echo Lake in the model) will require an EIS and a ROD permitting BPA to take action. If the W1 and W4 plans require this line, Everett Delta cannot be offered the transmission service until the date of the ROD. However, contingency analysis for both plans appear to indicate that this line is not needed to accommodate Everett Delta transmission service. The effect of Everett Delta generation without the line is an improved Custer to Ingledow flow limit during winter conditions.

9.6 Future Reliability Management

A critical assumption for the future is that predicted power flow will be maintained within reliability limits in the scheduling time frame prior to actual operation. Operating action to reduce power flow within reliable limits is assumed only for unplanned outages within the hour. Simultaneous conditions cannot reliably occur without significant system expansion. Therefore, for this assumption to be correct, effective paths within the network will need to be defined. Transfer capabilities on the paths will need to be calculated. Accurate forecasts of path uses will be needed. Effective curtailment or generation redispatch procedures will be needed in the scheduling time frame, if the path use is forecasted to exceed the transfer capability calculations.

10 Conclusion

System expansion is needed to accommodate the Everett Delta transmission requests. The scope of the initial system facilities could be limited to RAS, depending on the outcome of the issues raised in section 9. The scope of system expansion to accommodate simultaneous uses with the 500 MW generation level could involve a new line, such as a Snohomish-Snoking 230kV line, depending on the outcome of issues raised in section 9.

The system expansion prerequisites for 500 MW of transmission service will also depend on the determination of the committed uses. This effort is currently in progress. It will be part of an RTO West filing with FERC scheduled for June 2001.

A Facilities Study agreement needs to be tendered to the requestor. The study needs to address both the system expansion and the interconnection components. The interconnection component includes developing the plan for the host control area facilities and a plan for the 230kV interconnection at Snohomish for the 500 MW generation level.